Revenue Requirements Analysis

Adopted 2017-2018 Rates

October 10, 2016

Contents

Executive Summary

S.1 Revenue Requirements

City Light's 2017 and 2018 revenue requirements are consistent with the 2017-2022 Strategic Plan Update.[1] Table S1 shows the 2017 and 2018 revenue requirements and the respective annual changes.

Table S1
Revenue Requirements

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Revenue Requirement	$807.4	$851.7	$901.9	$44.3	$50.2

S.2 Drivers of the Increase in Revenue Requirements

The drivers of the **$44.3 million** increase between 2017 and 2016 are:
Increases
- $15.9 million higher debt service coverage requirements
- $7.7 million higher power contract expenses, mostly BPA
- $9.2 million increase to non-power direct O&M (higher labor wages, benefit costs)
- $0.6 million decrease in power revenues
- $2.4 million higher taxes, uncollectible revenue, and other miscellaneous expenses
- $9.0 million from the difference in the actual debt service coverage

Decreases (Offsets)
- $0.6 million higher miscellaneous revenues (e.g. other revenue, RSA transfers)

The drivers for the **$50.2 million** change between 2018 and 2017 include:
Increases
- $25.3 million higher debt service coverage requirements
- $5.7 million higher power contract costs (BPA power, wheeling)
- $15.9 million increase to non-power direct O&M (strategic initiatives, inflation)
- $2.4 million higher taxes, uncollectible revenue, and other miscellaneous expenses
- $1.0 million decrease to power revenues

Figure S1 gives a high-level graphical view of the 2017 and 2018 revenue requirement drivers.

[1] Adopted by City Council in July 2016.

Figure S1
High-Level Revenue Requirements Drivers

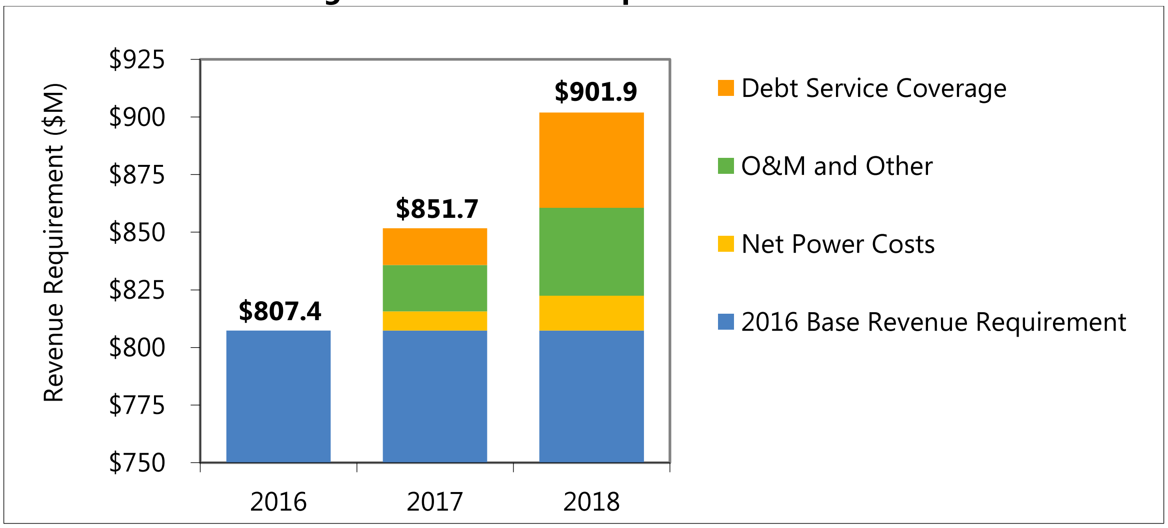


Table S2 provides a summary of the costs and expenses assumed in the revenue requirement.

Table S2
2017-2018 Revenue Requirements Calculation Summary

Chapter	RRA Category ($ Millions)	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
1	Debt Service	$197.4	$206.2	$220.3	$8.9	$14.1
	Debt Service times 1.8	**$355.3**	**$371.2**	**$396.5**	**$15.9**	**$25.3**
2	**Operating Expenses**					
	Power Contracts	$275.9	$283.6	$289.3	$7.7	$5.7
	Non-Power O&M	255.5	264.8	280.7	9.2	15.9
	Other Expenses	44.9	47.3	49.7	2.4	2.4
	Total	**$576.3**	**$595.7**	**$619.7**	**$19.4**	**$24.0**
3	**Operating Revenues**					
	Net Wholesale Revenue	$60.0	$60.0	$60.0	$0.0	$0.0
	Power Revenues	21.2	20.6	19.6	(0.6)	(1.0)
	Other Sources	34.0	$34.5	34.7	0.6	0.1
	Total	**$115.2**	**$115.2**	**$114.3**	**($0.0)**	**($0.9)**
4	**Revenue Requirements**					
	Expected	$807.4	$851.7	$901.9	$44.3	$50.2
	Target	816.4	851.7	901.9	35.3	50.2
	Difference*	($9.0)	$0.0	$0.0	$9.0	$0.0

*The target revenue requirement is the retail revenue needed to meet the 1.8x debt service coverage. The expected retail revenue in the 2016 Plan is based off of retail sales from the 2015 load forecast, which was slightly lower than the load forecast used to set 2016 rates. This is the primary reason for difference from the target revenue requirement. In addition, there are also small changes in the budgeted revenues and expenses from the planned levels when 2016 rates were set. Chapter 4 discusses the difference between the target and expected revenue requirement in detail.

S.3 Changes in Average Rates

The 2017-2022 Strategic Plan Update calls for rate increases averaging **5.6%** in 2017 and **5.6%** in 2018. Table S3 summarizes retail revenue, average rates and annual rate increases for 2017 and 2018. The first section shows the retail revenue generated from existing rates and the incremental retail revenue in 2017 and 2018. The second section provides the average rates for each year, which are calculated by dividing total retail revenue by the total sales to customers and multiplying by 100 (to get cents/kWh). The third section shows the average annual rate increase and a breakout showing how much of the increase is due to increases in the revenue requirement and how much is due to changes in the amount of expected retail customer sales.

Table S3
Changes in Average Rates

	2016 Plan	2017	2018
Retail Revenue ($M)[2]			
From 2016 Rates	$807.4	$806.6	$808.6
From 2017 Increase		$45.1	$45.4
From 2018 Increase			$47.9
Retail Revenue Requirement[3]	**$807.4**	**$851.7**	**$901.9**
Sales to Retail Customers (GWh)	9,441	9,432	9,456
Average Rates (cents / kWh)			
From 2016 Rates	8.55	8.55	8.55
After 2017 Increase		9.03	9.03
After 2018 Increase			9.54
Annual Rate Increase		**5.6%**	**5.6%**
Change from Increased Revenue Requirement		5.5%	5.8%
Change from Expected Retail Sales		0.1%	-0.2%

The average annual rate increase is calculated compared to the average system rate for the previous year. It is possible that changing retail electricity consumption patterns can result in different average rates. For example, if customer consumption patterns change it could make the average rate in 2017 under current rates higher or lower than the 8.55 ¢/kwh listed. Note that an average rate is only a statistic and not actually a customer rate.

[2] Retail revenue from energy charges, demand charges and base service charges from all customers.
[3] There are some very small differences in the 2017 and 2018 revenue requirements compared to what was reported in the 2016 Strategic Plan. The differences are less than $0.2M and come from different interest earning calculations due to changes in the monthly shaping of O&M costs.

The 2017-18 Rate Study is a comprehensive one; therefore, the revenue requirement is only the first of three steps. First the revenue requirement is calculated, then the cost of service and cost allocation study divides the revenue requirement dollars among customer classes, and then finally rate design sets individual rates to collect this revenue. Therefore, the revenue requirement determines that the average rate increase across all customers is 5.6% in both 2017 and 2018, but each individual customer class will have a different rate increase that could be lower or higher than the system average.

Introduction

I.1 Introduction

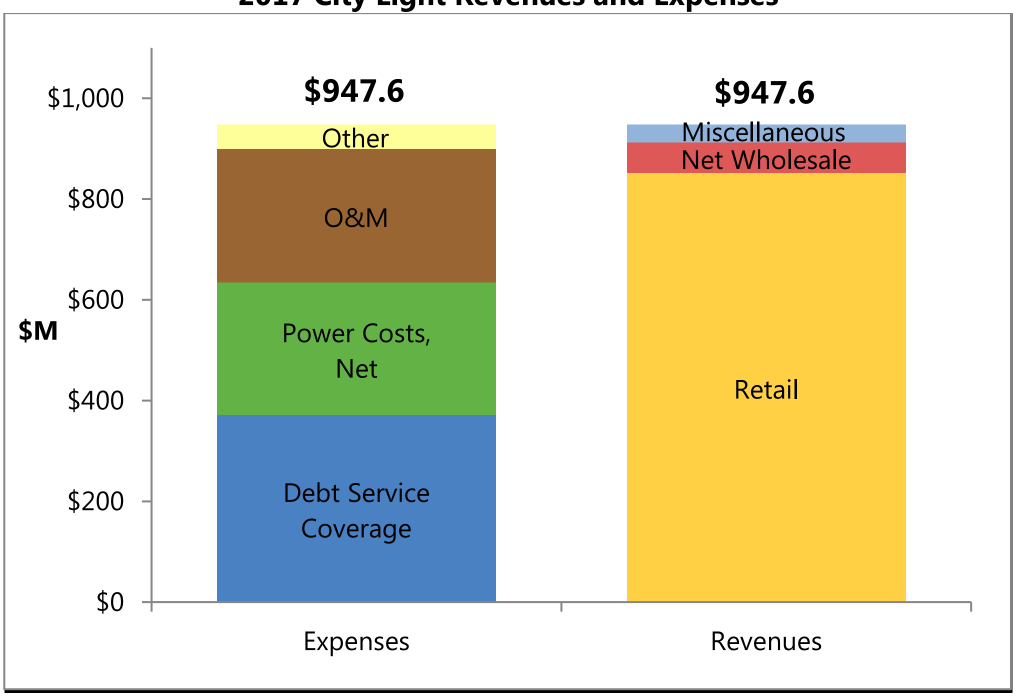
The revenue requirements analysis (RRA) determines the amount of revenue that City Light must collect from retail customers in a given year to cover operating costs and meet Council-mandated financial policies. Operating revenues, operating costs and capital expenditures (which drive debt service coverage) are determined by the budget, which is developed in conjunction with the revenue requirement. City Light's current rate setting financial policy[4] specifies that rates should be set so that after all operating expenses the remaining net revenue will be equal to 1.8 times debt service. The amount of net revenue available for debt service is also commonly referred to as debt service coverage.

The following equation demonstrates the basic derivation of the revenue requirements:

Revenue Requirements = Debt Service * 1.8 + Operating Expenses – Non-Rate Based Revenues

Figure 1 below shows how retail revenue is sized so that total revenues equal total expenses. It also illustrates the relative size of City Light's revenues and expenses.

Figure 1
2017 City Light Revenues and Expenses



[4] City Council Resolution 31187 passed in March 2010.

The revenue and expenses used in the derivation of revenue requirements are consistent with the methodology for calculating debt service coverage for ratemaking. Note that revenue requirements use a slightly different definition of operating revenues and expenses than is used in the income statement, because the income statement includes non-cash transactions such as depreciation and mark-to-market valuation for certain energy purchases and sales. These types of transactions are not part of the debt service coverage calculation. City Light's 2015 Annual Financial Report provides information on specific types of adjustments made to the income statement categories.

I.2 RRA Objectives and Organization

The RRA's two main objectives are (1) to summarize how the 2017 and 2018 revenue requirements are determined and (2) to explain what has changed from the revenue requirements used to set the existing 2016 rates. To accomplish this, this report compares the forecast for the 2017 and 2018 revenues and expenses to the forecast that determined the 2016 rates, referred to as the "2016 Plan". The 2016 Plan includes the 2015 BPA retail rate pass-through that went into effect October 1, 2015. Note that 2016 actuals are not pertinent to this discussion; the RRA only compares the current proposal to the revenues and expenses used to determine the existing 2016 rates.

The RRA is organized into 5 chapters with appendices providing additional detail. Chapter 1 explains debt service and debt service coverage. Chapter 2 discusses operating expenses while Chapter 3 discuses non-rate based revenue. The revenue requirement, which is calculated from the values in Chapters 1-3, is summarized in Chapter 4. Finally, Chapter 5 discusses indirect costs and proceeds, such as capital expenses and proceeds from bond issues. These impact the revenue requirements indirectly through their role in size and timing of future debt issues, which ultimately impact future revenue requirements.

Chapter 1: Debt Service and Debt Service Coverage

City Light finances a portion of its capital program by selling municipal power bonds. The bonds are paid back over a term of 20 to 30 years through interest and principal payments, also called debt service. At the end of 2015 City Light held around $2.07 billion in long-term debt obligations. City Light's financial policies require it to set rates sufficient to cover debt service 1.8 times after all required operating expenses are paid. Therefore, changes in debt service have 1.8 times the impact on the revenue requirements that other expenses have.

For the purpose of the financial forecast and the revenue requirements, federal interest subsidies are subtracted from interest payments instead of treating them as revenue.[5] Also, a 6.8% reduction in planned subsidy payments is assumed, to reflect the potential of reductions due to federal sequestration. Table 1.1 shows the debt service projections for the 2016 Plan compared with the forecast for 2017 and 2018 and the year to year changes. The debt service coverage requirement is increasing in both 2017 and 2018. A number of key infrastructure projects are currently in progress, such as the Denny Substation, Advanced Metering and Alaskan Way Viaduct Infrastructure Relocation projects. As a result, current capital requirements are significantly larger than historical levels.

Table 1.1
Debt Service and Debt Service Coverage

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Debt Service, Gross	$202.8	$212.2	$226.3	$9.4	$14.1
Federal Subsidies	-5.5	-6.0	-6.0	-0.5	-0.0
Debt Service, Net of Subsidies	197.4	206.2	220.3	8.9	14.1
Debt Service Coverage (at 1.8x)	**$355.3**	**$371.2**	**$396.5**	**$15.9**	**$25.3**

Forecasted debt issues are sized to meet City Light's forecasted cash requirements for approximately 12 months, resulting in annual debt issues each year. Details of the planned debt issues are shown below in Table 1.2. Future debt issues in 2017 and 2018 are assumed to be fixed rate debt and do not anticipate any refinancing of existing debt.

[5] Federal interest subsidies are subsidies City Light receives on Build America Bonds (BABs), Conservation and Renewable Energy Bonds (CREBs) and Recovery Zone Economic Development Bonds (RZEDs). Traditional accounting treats the subsidies as revenues. With approval from City Light's financial advisors, the financial forecast does not count the subsidies as revenue but rather subtracts the subsidies from debt service and uses net debt service in the debt coverage calculations.

Table 1.2
Planned Debt Issues

Year	Debt Issue Amount ($M)	Term (years)	Average Rate
2016 Planned - Fixed Rate (Sep)	148.0	30	4.5%
2016 Planned - Variable Rate (Oct)	100.0	30	1.4%
2017 Planned Issue	275.0	30	5.0%
2018 Planned Issue	250.0	30	5.0%

Table 1.3 shows existing debt service in total and future debt service by issue year. Debt service on future debt is expected to increase from current levels driven by the Capital Improvement Plan (CIP). The CIP is discussed in detail in Appendix C.

Table 1.3
Debt Service

$ Millions	2016 Plan	2017	2018
Debt Service on Existing Debt (as of Feb 2016)	**$202.3**	**$199.4**	**$195.2**
Debt Service on Future Debt			
2016 Bonds - Fixed Rate (Sep)	-	9.0	9.0
2016 Bonds - Variable Rate (Oct)	0.5	3.7	4.2
2017 Bonds	-	-	17.8
2018 Bonds	-	-	-
Subtotal	**0.5**	**12.8**	**31.1**
Total Gross Debt Service	**$202.8**	**$212.2**	**$226.3**
Federal Subsidies	-$5.5	-$6.0	-$6.0
Total Debt Service Net of Subsidies	**$197.4**	**$206.2**	**$220.3**

Chapter 2: Operating Expenses

2.1 Introduction

Operating expenses are grouped into power contract expenses, non-power O&M and other expenses. Table 2.1 summarizes the expected annual operating expenses and the respective annual changes.

Table 2.1
Operating Expenses

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Power Contracts	$275.9	$283.6	$289.3	$7.7	$5.7
Non-Power O&M	255.5	264.8	280.7	9.2	15.9
Other Expenses	44.9	47.3	49.7	2.4	2.4
Total	**$576.3**	**$595.7**	**$619.7**	**$19.4**	**$24.0**

2.2 Power Contract Expenses

Power contract expenses include the costs City Light pays to third parties for the acquisition and transmission of energy. Table 2.2 summarizes the expected annual power contract expenses and the respective annual changes. A more detailed description of power contracts is located in Appendix A.

Table 2.2
Power Contract Expenses

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Long-Term Purchased Power					
BPA	$167.5	$175.2	$180.6	$7.8	$5.4
Priest Rapids	2.5	2.4	2.2	(0.1)	(0.2)
Columbia Basin Hydro	6.6	6.7	6.9	0.2	0.2
High Ross	13.1	13.1	13.1	0.0	0.0
Lucky Peak	7.5	7.7	7.9	0.2	0.2
Stateline Wind Project	24.5	24.6	24.7	0.1	0.1
Small Renewables	10.9	10.0	8.6	(0.9)	(1.4)
Subtotal	**$232.5**	**$239.7**	**$244.0**	**$7.2**	**$4.2**
Wheeling					
BPA Firm Wheeling	$42.1	$42.6	$44.1	$0.5	$1.5
South Fork Tolt	0.4	0.4	0.4	(0.0)	(0.0)
Other, Net	0.8	0.8	0.8	0.0	0.0
Subtotal	**$43.3**	**$43.8**	**$45.3**	**$0.5**	**$1.5**
Total Power Contracts	**$275.9**	**$283.6**	**$289.3**	**$7.7**	**$5.7**

Long-Term Purchased Power Expenses
The forecast of power expenses is based on the power contract budget. In some cases the forecast uses different values than the budget and these differences are discussed in Appendix B. Total long-term purchased power expenditures are forecasted to increase in 2017 and 2018 primarily due to inflationary increases in BPA expenses (See *BPA expenses*). With the sole exception being the expiration of the Stateline Wind contract in 2022, the forecast projects no major contract changes, and no new resources are expected to be procured.

Wheeling Expenses
Wheeling expenses consist of payments for transmission services under long-term contracts. As shown in Table 2.2, BPA is City Light's primary provider of wheeling services (see *BPA Expenses*). Wheeling expenditures are forecasted to increase in 2017 and 2018 due primarily to inflation.

BPA Expenses
BPA power and wheeling expenses assume CPI inflation of approximately 2.4% per year. In the 2018 federal fiscal year beginning October 1, 2017, BPA rates may increase more or less than this amount. When the final decision is published in late summer of 2017, City Light will evaluate the effect of new BPA rates in relation to expense assumptions. Any costs above or below what is included in base rates will be recovered or returned through the automatic BPA pass-through mechanism, pursuant to SMC 21.49.081.

2.3 Non-Power Operating and Maintenance Expenses

Non-power operating and maintenance expenses are the costs associated with day-to-day operations. This is a large and diverse category of costs that include functions such as power production, distribution and transmission system operation and maintenance, customer services such as billing and meter reading, and administrative support.

Non-Power O&M Budget
The basis for the non-power O&M in the financial forecast is the 2017-2018 budget, adjusted to remove costs that do not impact debt service coverage. (This adjustment is discussed in more detail below.) Table 2.3 summarizes the expected annual non-power O&M by budget category and the respective annual changes.[6]

[6] For more detail see City Light's 2017-2022 Strategic Plan.

Table 2.3
2017 and 2018 O&M

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Labor	$139.0	$142.5	$146.4	$3.5	$3.9
Labor Benefits	75.3	79.0	83.0	3.8	4.0
Non-Labor	78.7	80.6	82.6	1.9	1.9
Transfers to City	33.7	34.7	35.8	1.0	1.0
Operating Supplies	15.7	16.9	18.3	1.2	1.4
Total	**$342.4**	**$353.8**	**$366.0**	**$11.4**	**$12.2**
Annual Labor Increase		2.52%	2.74%		
Average Growth All O&M		3.30%	3.51%		

O&M Category	Annual Inflation	Notes
Labor	see above	2017 and 2018 from Central Budget Office, 2.4% in out years
Labor Benefits	5.0%	Conservative value based on history
Non-Labor	2.4%	Assumed to grow at close to CPI inflation
Transfers to City	3.0%	Assumed to grow at a rate slightly higher than CPI inflation
Operating Supplies	8.0%	Includes IT equipment and software, fuel costs, inventory material for distribution and generation systems. Growth assumed to remain high (conservative placeholder)

Adjustments from Inflated 2016 Budget to Financial Forecast

To correspond with City Light's debt service coverage policy, the O&M budget is adjusted to include only costs that will be applied to the debt service coverage calculation. This includes adjustments such as: removing deferred O&M and all projected capitalized and deferred labor loadings, as well as any items that are not budgeted in non-power O&M but are included in non-power O&M in the financial forecast. In addition, a $10 million under expenditure assumption was included in the financial forecast. This reflects roughly 3-4% of total O&M and is consistent with the under spending of the O&M budget over the past few years. Table 2.4 provides a summary of the budget-to-forecast adjustments and the resulting non-power O&M expenses used in the financial forecast.

Table 2.4
Summary of Budget to Forecast Adjustments

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Inflated 2016 Budget	**$342.4**	**$353.8**	**$366.0**	**$11.4**	**$12.2**
REC Expense[1]	3.4	3.5	4.9	0.1	1.4
3rd AC Intertie Expense[1]	1.1	0.9	0.9	-0.2	0.0
PNCA Payment[1]	1.9	1.9	1.9	0.0	0.0
Capital Loadings[2]	-83.3	-86.2	-89.1	-2.9	-3.0
Under Expenditure[3]	-10.0	-10.0	-10.0	0.0	0.0
Strategic Adjustments[4]	0.0	0.8	6.1	0.8	5.3
Total O&M	**$255.5**	**$264.8**	**$280.7**	**$9.2**	**$15.9**

[1] Items that are budgeted as purchased power but recognized as O&M in forecast.

[2] Remove capital loadings and overhead expenses associated with the CIP from the O&M budget, include these expenses as capital requirements. CIP and deferred overheads are expected to increase at a rate of 3.4% per year, predicated on the assumption that labor levels will remain constant for CIP and deferred O&M over the six-year planning period.

[3] Remove $10 million per year to reflect an assumption of budget under expenditure.

[4] Strategic adjustments encompass all discretionary changes to O&M. See the Strategic Plan Financial Assumptions Document, Appendix A for further detail.

2017 O&M increases are largely driven by annual inflation assumptions. 2018 O&M is expected to increase due to a combination of annual inflation assumptions and strategic adjustments. Strategic adjustments include both changes to baseline programs as well as initiatives identified in previous strategic plans (see the Strategic Plan Update 2017-2022, Appendix A for further detail).

These year-over-year increases in forecasted non-power O&M account for roughly 21% and 32% of the total increase in 2017 and 2018 revenue requirements, respectively.

2.4 Other Expenses

Other expenditures include uncollectable accounts, state taxes, other (non-City) taxes and franchise payments.[7] Other expenditures generally grow in proportion with the revenue requirement. Table 2.5 summarizes the other expenses and the annual changes.

[7] Taxes paid to the City of Seattle are junior to debt service and therefore are not included in the calculation of debt service coverage.

Table 2.5
Other Expenses

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Uncollectable Accounts	$6.1	$6.4	$6.8	$0.3	$0.4
State Taxes	29.3	30.7	32.2	1.4	1.5
Other (non-City) Taxes	3.3	3.8	3.9	0.5	0.1
Franchise Payments	6.2	6.4	6.8	0.2	0.4
Total	**$44.9**	**$47.3**	**$49.7**	**$2.4**	**$2.4**

Uncollectable Accounts

Every year, a portion of past-due accounts receivable are never received, despite collection efforts, and must be written off as uncollectable. Uncollectable accounts refer to both retail customers and wholesale counterparties. Uncollectable revenue is projected to remain at around 0.75% of revenue from energy sales to retail customers.

State Taxes

City Light pays a state utility tax on retail revenue and some other sources of outside revenue including Contributions in Aid of Construction (CIAC). It is assumed that 6% of these revenues, representing taxes paid to the City, are not taxable and deducted from the tax base. The remaining revenue is taxed at the State rate of 3.8734%. These taxes are projected to be slightly higher in 2017 and 2018 because of increases in retail revenue. In addition to the state utility tax, City Light pays a state business tax, which amounts to around $0.1 million per year.

Other (non-City) Taxes

City Light makes payments to some states, counties and school districts where its production facilities are located. Excluding a $0.4 million reduction in 2016 taxes that relates to 2015, other tax payments are forecasted to increase approximately 3% annually in both 2017 and 2018.

Payments to Franchise Cities

City Light makes payments to suburban cities with which it has negotiated franchise agreements to construct, operate, replace, and repair the electric and light system to serve those areas. These are calculated as a percentage of the projected retail revenue billed to customers in these suburban cities. They are projected to increase in both 2017 and 2018 due to changes in franchise agreement terms, retail rates and energy consumption characteristics.

Chapter 3: Non-Rate Based Revenue

3.1 Introduction

In addition to revenue from retail sales, City Light receives cash from other non-rate sources such as wholesale power sales, long-term power contracts, transmission and power-related services, investment income and other fees and charges. Table 3.1 summarizes forecasted non-rate based revenues and the annual changes.

Table 3.1
Non-Rate Based Revenues

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Net Wholesale Revenue	$60.0	$60.0	$60.0	$0.0	$0.0
Power Revenues	21.2	20.6	19.6	(0.6)	(1.0)
Other Sources	34.0	34.5	34.7	0.6	0.1
Total	**$115.2**	**$115.2**	**$114.3**	**($0.0)**	**($0.9)**

3.2 Net Wholesale Revenue

City Light participates in the wholesale market selling or purchasing power when its power supply is surplus or deficit of its retail load. In addition, City Light often takes advantage of the storage in its dams and purchases power in lower priced periods and sells it in higher priced periods. Revenue from wholesale power sales net of purchases, also commonly referred to as net wholesale revenue (NWR), is the net cash derived from energy sales and purchases on the wholesale market. Table 3.2 lists the assumptions for NWR, which is also the baseline value for the Rate Stabilization Account (RSA) and consistent with the 2017-2022 Strategic Plan. There is no change from 2016 levels.

Table 3.2
Planning Value for Net Wholesale Revenue

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Net Wholesale Revenue	$60.0	$60.0	$60.0	$0.0	$0.0

3.3 Power Revenues

Power revenues include revenue received from long-term power contracts and revenue (net of purchases) from various marketing activities. Table 3.3 details these revenues and the annual changes.

Table 3.3
Summary of Power Revenues

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Revenue from Power Contracts					
Article 49 Sales to PO County	$2.0	$2.1	$2.1	$0.0	$0.0
Sales from Priest Rapids	2.4	2.3	2.2	(0.1)	(0.1)
BPA Credit for South Fork Tolt	3.3	3.1	3.0	(0.2)	(0.2)
BPA Residential Exchange Credit	5.7	5.7	5.7	(0.0)	0.0
Subtotal	**$13.4**	**$13.2**	**$13.0**	**($0.2)**	**($0.2)**
Power Marketing Revenue, Net					
Transmission Revenue	$3.4	$3.4	$3.4	$0.0	$0.0
Sale of Lucky Peak Output	0.1	0.1	0.0	0.0	(0.0)
REC Sales	4.5	4.5	4.5	(0.0)	0.0
Other Services, Net	(0.2)	(0.6)	(1.3)	(0.4)	(0.8)
20.6	**$7.8**	**$7.4**	**$6.7**	**($0.4)**	**($0.8)**
Total	**$21.2**	**$20.6**	**$19.6**	**($0.6)**	**($1.0)**

Power Contracts
This revenue category includes contractual payments that City Light receives from third parties. Similar to the power contract expenses, the forecast is based on the biennial power contract budget. Power contract revenue is projected to decline slightly in both 2017 and 2018 driven primarily by declining revenue from the BPA South Fork Tolt credit.

Power Marketing, Net
Power Marketing revenues include sales of surplus transmission capacity, premiums associated with the sale of Lucky Peak output, Renewable Energy Credits (RECs), as well as purchases and sales of other ancillary services (e.g., reserve energy and capacity, parking and shaping) that extract value from City Light's generation assets. Power marketing revenue is projected to decline slightly in both 2017 and 2018 because of the phasing out of a financial settlement component of the SMUD exchange contract, which expires in 2017 (The SMUD exchange is included in Other Services, Net in Table 3.3).

3.4 Other Revenue Sources

This category includes cash from a variety of sources such as late payment fees, property rentals, sales of property, investment income, operating fees and grants. Other revenues are generally projected using historical information and inflation. Table 3.4 shows the forecast of other revenue sources.

Table 3.4
Revenue from Other Sources

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Other Revenue	$22.7	$22.9	$23.2	$0.2	$0.2
Investment Income	6.6	8.0	7.8	1.4	(0.2)
Sale of Property	1.0	0.0	0.0	(1.0)	0.0
Suburban Undergrounding	1.1	1.4	1.5	0.3	0.1
RSA Transfers	(1.0)	(1.4)	(1.4)	(0.4)	(0.0)
Distribution Capacity Charge	0.2	0.2	0.2	0.0	0.0
Green Power Programs	1.5	1.5	1.6	0.1	0.0
Power Factor Charges	2.5	2.5	2.5	0.0	0.0
Less:					
Credits for Transformation	0.4	0.4	0.4	0.0	0.0
Emergency Low Income Assistance	0.3	0.3	0.3	0.0	0.0
Total	**$34.0**	**$34.5**	**$34.7**	**$0.6**	**$0.1**

Other revenue sources do not include revenues from the anticipated sale of the Roy Street property, which is expected to yield $18 million in revenue in 2016. Also excluded from 2016 revenues is the expected $2.3 million in operating grants. Per the strategic plan, these revenues are treated like capital program contributions, which only indirectly impact the revenue requirement by reducing the amount of debt issued.

Investment income is forecasted to increase due to forecasted interest rates rising from 1.12% in 2016 to 1.50% in 2017.

Chapter 4: Retail Revenue from Base Rates

Revenue Requirement

The revenue requirement the total amount of revenue City Light needs to collect from all customers in a given year. It is comprised of retail revenue collected through retail customer rates. Revenue requirements are shown net of any rate discounts given to Utility Discount Program customers. The revenue requirements are $851.7 million in 2017 and $901.9 million in 2018, and result in annual rate increases of 5.6% in both years.

City Light's rate setting guideline[8] calls for retail rates be set so that after all operating expenses are paid, there will be enough net revenue remaining to cover the annual debt service by 1.8 times. Table 4.1 shows that the 2017 and 2018 revenue requirements meet this financial policy given the debt service, operating expenses and non-retail operating revenues discussed in Chapters 1 through 3.

Table 4.1
Debt Service Coverage with Retail Revenue Requirements

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Retail Revenue	$807.4	$851.7	$901.9	$44.3	$50.2
Operating Expenses	576.3	595.7	619.7	19.4	24.0
Non-Rate based Revenue	115.2	115.2	114.3	(0.0)	(0.9)
Amount Available for Coverage	**$346.3**	**$371.2**	**$396.5**	**$24.9**	**$25.3**
Debt Service	$197.4	$206.2	$220.3	$8.9	$14.1
Debt Service Coverage Ratio	1.75	1.80	1.80	0.05	0.00

As shown below in table 4.2 the target revenue requirement is the retail revenue needed to provide exactly 1.80x debt service coverage. Table 4.1 shows that the 2016 debt service coverage is not exactly 1.80. The retail revenue in the 2016 Plan is calculated by multiplying retail sales from the 2015 load forecast by the adopted 2016 rates. The 2015 load forecast was lower than the 2014 load forecast used in the 2015-2016 rate case, and the 2016 Plan retail revenue reflects the resulting under-collection. Therefore, there is an additional $9.0 million target-to-expected difference that needs to be accounted for to explain the entire $44.3 million dollar change in the 2017 revenue requirement.

[8] Established by Resolution 31187.

Table 4.2
Adopted-Target Differences

$ Millions	2016 Plan	2017	2018	Difference 2017-2016	Difference 2018-2017
Expected Retail Revenue	$807.4	$851.7	$901.9	$44.3	$50.2
Target Revenue Requirement	816.4	851.7	901.9	35.3	50.2
Difference	**($9.0)**	**$0.0**	**$0.0**	**$9.0**	**$0.0**

Average Rates and Annual Rate Increases

Table 4.3 summarizes retail revenue,[9] average rates and annual rate increases for 2017 and 2018. The first section shows the retail revenue generated from existing rates and the nominal increases in retail revenue in 2017 and 2018. The second section provides the average rates for each year, which are calculated by dividing total retail revenue by the total sales to customers and multiplying by 100 (to get cents/kWh). The third section details the average annual rate increase and shows how much of the change is attributable to the revenue requirement and how much is due to changes in retail sales.

Table 4.3
Revenue Requirements and Average Retail Rates

	2016 Plan	2017	2018
Retail Revenue ($M)			
From 2016 Rates	$807.4	$806.6	$808.6
From 2017 Increase		$45.1	$45.4
From 2018 Increase			$47.9
Retail Revenue Requirement	**$807.4**	**$851.7**	**$901.9**
Sales to Retail Customers (GWh)	9,441	9,432	9,456
Average Rates (cents / kWh)			
From 2016 Rates	8.55	8.55	8.55
After 2017 Increase		9.03	9.03
After 2018 Increase			9.54
Annual Rate Increase		**5.6%**	**5.6%**
Change from Increased Revenue Requirement		5.5%	5.8%
Change from Expected Retail Sales		0.1%	-0.2%

The forecast of retail sales is based on City Light's official 2015 load forecast, which projects relatively flat sales between 2015 and 2018. Advancements in energy efficiency and intensified conservation efforts are offsetting additional demand due to population growth. Consequently, the change in load from year to year is forecasted to have minimal impact on the 2017 and 2018 average rate increases; these are being driven primarily by the increase in revenue requirements for each year.

[9] Retail revenue from energy charges, demand charges and base service charges from all customers.

Chapter 5: Indirect Costs and Proceeds

Indirect expenses and proceeds include capitalized and deferred expenses, City taxes, and cash adjustments. These do not directly impact the revenue requirement in the year in which they occur, but influence the amount of long-term debt issued in each year, which drives future revenue requirements through debt service coverage. Table 5.1 shows the indirect costs and proceeds for 2017 and 2018. Note that debt service and the amount available for debt service are discussed in Chapters 1 and 4, respectively.

Table 5.1
Indirect Costs and Proceeds

$ Millions	**2017**	**2018**
Cash From Operations		
Amount Available for Debt Service	$371.2	$396.5
less		
Debt Service	206.2	220.3
City Taxes	53.9	56.3
Cash Adjustments	18.7	18.3
Total	**$92.3**	**$101.6**
Sources of Capital Funding		
Cash from Operations	$92.3	$101.6
Cash from (to) Cash Balances	38.6	23.2
Bond Proceeds	267.6	243.3
Capital Contributions	42.7	31.3
Total	**$441.3**	**$399.3**
Capital Expenses		
CIP	$391.9	$346.2
Deferred O&M	49.4	53.2
Total	**$441.3**	**$399.3**

5.1 City Taxes

City Light pays the City of Seattle an occupation tax equal to 6.0% of retail revenue and some other sources of outside revenue including interest earnings and contributions in aid of construction (CIAC). In addition to the occupation tax, City Light pays the City of Seattle a small business tax. Unlike State taxes, taxes paid to the City of Seattle are junior to debt service and therefore are not included in the calculation of debt service coverage. Thus, City taxes are an indirect expense. City taxes increase proportionally with retail revenue.

5.2 Roy Street Property Sale

As mentioned in section 3.4, City Light plans on selling a property on Roy Street in 2016 for $18 million. This large sale will not directly impact debt service coverage but the proceeds will reduce the amount of debt issued in 2016, reducing future debt service.

5.3 Cash Adjustments

Implicit in the amount available for debt service are a number of operating costs and revenues that are accounted for on an accrual basis but the actual cash transactions are lagged. Cash adjustments are made for costs/revenues that are accrued in the previous year but which will be paid/received in the current year, and for costs/revenues that have been accrued in the current year but which will be paid/received in the following year. For example, the retail revenue discussed in Chapter 4 is accrued revenue based on the energy that will be delivered to customers in the current year. City Light will still have to read the meters, bill the customers and collect the payments. Thus, there will be a lag from the time the retail energy is delivered and the revenue is accrued to when the payments are received. Cash adjustments are made to estimate the amount of operating cash flow that will be available for the capital program. These cash flows are referred to as cash from operations, which are treated as a source of capital funds.

In addition to cash lags, certain elective cash transfers also restrict operating funds, making them ineligible to put towards the capital program. The forecast assumes annual transfers of $10 million in operating cash to the restricted bond reserve, in addition to regular bond reserve deposits needed to meet reserve requirements. This is a policy decision intended to gradually build up funds to replace the existing $77.1 million surety bond, which is set to expire in 2029.

5.4 Capital Requirements and Funding Sources

Capital requirements and funding sources are not a direct component of the revenue requirement, but determine the amount of debt (bonds) that must be issued. The principal payments on outstanding debt and associated interest expense make up debt service, which directly impacts the revenue requirement.

Table 5.2 presents a high level overview of all capital expenditures and funding sources. See Appendix C for more details about the capital program and its funding sources.

Table 5.2
Total Capital Expenditures and Funding Sources

$ Millions	2016	2017	2018	2019	2020	2021	2022	Total
Funds Required								
CIP	$420.1	$391.9	$346.2	$278.4	$297.6	$395.6	$350.0	$2,129.8
Conservation	35.0	35.7	36.4	37.1	37.9	38.6	39.4	220.8
High Ross Payment Amortization	9.1	9.1	9.1	9.1	9.1	-	-	45.5
Relicensing, Mitigation and Other	12.3	4.6	7.7	7.2	6.5	10.7	11.0	48.9
Total Funds Required	**$476.5**	**$441.3**	**$399.3**	**$331.9**	**$351.2**	**$444.9**	**$400.4**	**$2,445.0**
Funds Available								
Cash from Operations	$79.8	$92.3	$101.6	$105.6	$115.4	$131.6	$138.5	$626.3
Cash from Contributions	54.7	42.7	31.3	33.5	34.8	37.7	39.6	234.7
Cash from Bond Sale	292.1	267.6	243.3	218.9	267.6	243.3	218.9	1,532.7
Cash from Working Capital	49.8	38.6	23.2	(26.2)	(66.6)	32.4	3.4	51.3
Total Funds Required	**$476.5**	**$441.3**	**$399.3**	**$331.9**	**$351.2**	**$444.9**	**$400.4**	**$2,445.0**

Sources of Capital Funding

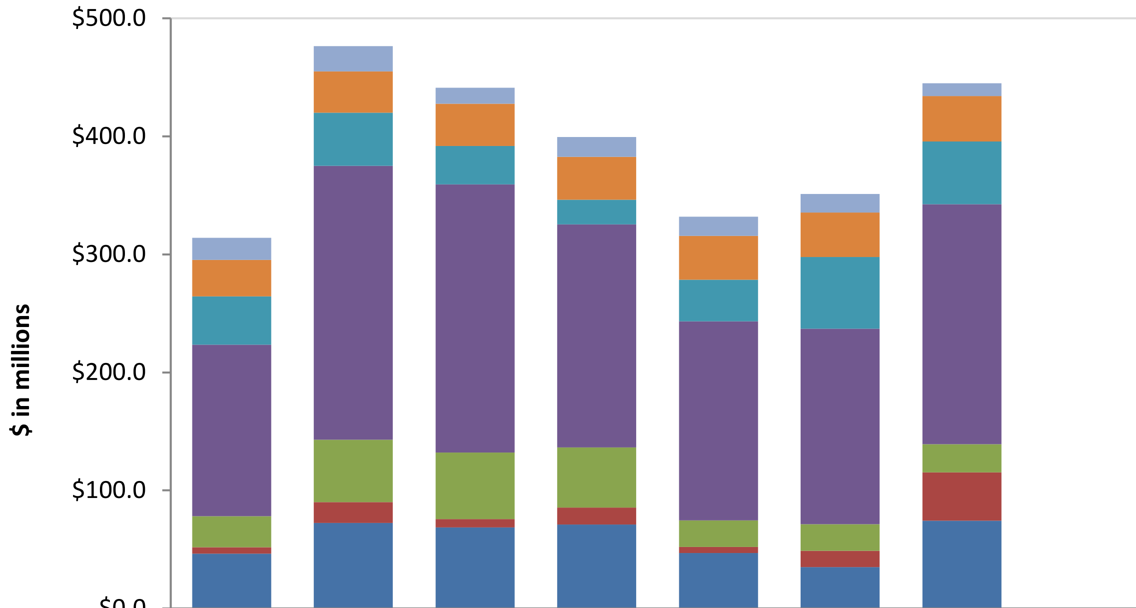
Capital funding from operations reflects cash drawdowns, and may represent net operating proceeds from the current or previous year(s). Funding from operations is the sum of the cash from operations line and cash to/from cash balances line in Table 5.1. City Light anticipates that it will fund its capital program with operating proceeds of $130.9 million in 2017 and $124.8 million in 2018.

Capital funding from contributions include third-party funding or reimbursements for capital or deferred O&M expenses. Examples include reimbursements for service connections and some transportation projects.

Capital Requirements

Capital requirements reflect City Light's CIP and certain O&M costs that have been approved to recover over time (deferred O&M). The bar chart on the next page shows the capital requirements approved in City Light's 2017-2022 Strategic Plan. CIP expenditures reflect the Adopted 2016-2021 CIP reduced by 10% to reflect an assumption for budget under-expenditure. The CIP also includes a few additional adjustments approved in the Strategic Plan, which reflect known changes to current project schedules, increased funding requirements for some existing projects, and a few new projects. These adjustments are reflected in the 2017-2022 CIP Budget. Appendix C provides more detail on City Light's CIP program.

Figure 5.1
Capital Requirements



	2011-15 Avg 2015 Dollars	2016	2017	2018	2019	2020	2021	Total 2016-2021
Other Deferred	18.6	21.4	13.7	16.8	16.3	15.6	10.7	94.5
Conservation	31.0	35.0	35.7	36.4	37.1	37.9	38.6	220.8
General Plant	40.8	45.0	32.6	20.8	35.1	60.7	53.0	247.1
Distribution	145.4	232.1	227.0	188.9	168.7	165.6	203.4	1,185.8
Substation	26.3	52.8	56.5	51.0	22.4	22.4	23.9	229.0
Transmission	5.5	17.6	6.9	14.3	5.2	14.0	41.0	99.0
Generation	46.5	72.6	68.8	71.1	47.1	35.0	74.3	368.8
Total Expenditure	313.9	476.5	441.3	399.3	331.9	351.2	444.9	2,445.0

A number of key infrastructure projects are currently in progress, such as the Denny Substation, Advanced Metering and Alaskan Way Viaduct Infrastructure Relocation projects. As a result, current capital requirements are significantly larger than historical levels.

Deferred O&M costs are displayed in Figure 5.1. Conservation installations are considered to be long-term energy resource investments and have been deferred since 1984 per Council Resolution 27372. Some costs associated with the High Ross Agreement, environmental cleanup, and some relicensing of City Light dams are also treated as deferred, and are in the "other deferred" category. While these costs do not produce assets, they still relate to activities that have impacts extending beyond the year those payments are made. Environmental cleanup costs of Superfund and other sites have been amortized since 2013.

Appendix A: Power Contracts Details

Bonneville Power Administration (BPA)
City Light has a 17-year Power Sales Agreement with BPA beginning October 1, 2011, according to which the power is delivered in two products: a shaped block product ("Block"), which is power provided in pre-determined amounts at pre-determined times, and a slice of the system product ("Slice"), which is a proportionate amount of power if, as, and when generated by the Federal System. The Slice and Block deliveries are approximately equal on an annual basis. Currently, City Light receives 265 aMW of the Block power annually, reduced by the amount of conserved energy savings purchased by BPA from the City Light. The Slice product provides City Light with a fixed 3.62762% of the actual output of the Federal System for federal fiscal year ("FFY") 2014 and obligates City Light to pay the same percentage of the actual costs of the Federal System. Under critical water conditions, the Slice purchase amounts to 263 aMW over the year. Power available under the Slice product varies with water conditions, federal generating capabilities, and fish and wildlife restoration requirements. City Light may resell output from the Slice product under specified conditions and may use the Slice product to displace its generation.

BPA is required by federal law to recover all of its costs through the rates it charges its customers. BPA conducts a rate case every two years, but the rates are subject to a cost recovery adjustment clause that allows rates to increase during a two-year rate period if certain events occur. In October 2015, BPA adopted new electric and transmission rates for FFY 2016-2017.

Priest Rapids
Under two agreements effective through 2052, City Light purchases a portion of the output of the Priest Rapids Project, which is owned and operated by Public Utility District No. 2 of Grant County ("Grant PUD"). The Priest Rapids Project, which is comprised of two dams, Priest Rapids and Wanapum, both located on the Columbia River, has an installed capacity of 1,893 MW. As of November 2009, City Light is obligated to purchase 6.14% of the output of both Priest Rapids dam (855 aMW total) and Wanapum dam (1,038 aMW total) available after Grant PUD meets its retail load. As Grant PUD's retail load increases, less electrical energy is available for City Light; City Light currently receives only about 2 aMW from these contracts. The Department also receives a portion of the revenues from an auction of 30% of the project power. Under the contracts, the Department is responsible for its percentage share of the costs of the Priest Rapids Project.

Columbia Basin Hydropower (formerly Grand Coulee)
City Light, in conjunction with the City of Tacoma Department of Public Utilities, Light Division ("Tacoma Power"), has power purchase agreements with three Columbia Basin irrigation districts for the acquisition of power from five hydroelectric plants under 40-year contracts expiring between 2022 and 2027. These plants, which utilize water released during the irrigation season, are located along irrigation canals in eastern Washington. The plants generate power only in the summer and thus have no winter peak capability. Plant output and costs are shared equally between City Light and Tacoma Power.

High Ross
In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia provides City Light power equivalent to that which would have resulted from an addition to the height of City Light's Ross Dam on the Skagit River that would have expanded the area flooded in British Columbia. The agreement was ratified through a treaty between Canada and the United States the same year. The power is to be received for 80 years, and delivery of power began in 1986. City Light will make annual payments to British Columbia of $21.8 million through 2020, which represents the estimated debt service costs City Light would have incurred had the addition been constructed. City Light also pays British Columbia the equivalent of the operation and maintenance costs which would have been incurred if the High Ross project had been built. The payments are charged to expense over a period of 50 years through 2035.

Lucky Peak
The Lucky Peak Hydroelectric Power Plant was developed by three Idaho irrigation districts and one Oregon irrigation district (the "Districts") and is located on the Boise River, approximately ten miles southeast of Boise, Idaho, at the Lucky Peak Dam and Reservoir. Its FERC license expires in 2030. The nameplate capacity is 101 MW, but the plant operates only during the irrigation season, so it provides no peak capacity during the Department's winter peak period.

In 1984, the Department entered into a power purchase and sales contract with the Districts under which the Department will purchase all power generated by the Lucky Peak Project, in exchange for payment of costs associated with the plant and royalty payments to the Districts. The Department also signed a transmission services agreement with Idaho Power Company ("Idaho Power") to provide for transmission of power from the Lucky Peak Project to a point of interconnection with the BPA transmission system.

City Light typically exchanges the entire output of the Lucky Peak plant for winter energy and a cash premium. For calendar years 2016 and 2017, Morgan Stanley Capital Group Inc. is the counterparty for the Lucky Peak exchange. There is not yet a contract for a 2018 exchange, so the forecast assumes an exchange with terms equivalent to those of 2016 and 2017.

Stateline Wind Project
An agreement with J.P. Morgan Ventures Energy Corp. provides for the City Light purchase of wind-generated power and associated renewable energy credits from the Stateline Wind Project in eastern Washington and Oregon. City Light purchases a percentage of the output from the Stateline Wind Project. The contract terms are from July 1, 2004, through December 31, 2021.

Through the end of the contract in 2021, the Department receives wind power with a maximum delivery rate of 175 MW per hour.

City Light also entered into a related ten-year agreement with PacifiCorp to purchase integration and exchange services for all of City Light's 175 aMW share of the Stateline Wind Project output. Under this agreement, PacifiCorp delivers the Department's share of the Stateline Wind Project output to the Mid-C market hub two months after it is generated. The integration and exchange agreement with PacifiCorp terminates at the end of 2021.

Small Renewables

SMUD: In 2007 City Light began a seasonal exchange with Sacramento (CA) Municipal Utility District (SMUD), in which City Light provides scheduling and delivery services for up to 15 aMW of power at the California-Oregon border that SMUD purchased from a renewable resource in the Pacific Northwest, the Sierra Pacific Industries Burlington Biomass Facility, which burns wood waste and produces electrical energy. City Light purchases from Sierra Pacific Industries all of the renewable energy and environmental attributes associated with the resource in excess of 15 aMW, or about 4 aMW. City Light used to receive up to 25 MW of winter energy from SMUD in payment for the services it provides, which has been replaced with a cash payment for the remainder of the contract. The contract expires in 2017.

Columbia Ridge Landfill Gas: In December 2009, City Light began taking delivery of 6 aMW per year and associated renewable energy credits (RECs) from the Columbia Ridge Landfill Gas project in Arlington, Oregon. The plant burns methane produced by the decomposition of solid waste in the landfill and has 6.4 MW of generation capacity. The City sends its solid waste to the landfill. Waste Management Renewable Energy (WMRE) is the developer, owner and operator of the project. The contract has a 20-year term, with specific prices and escalation rates. City Light redirected some transmission paths, and has firm transmission for project output to City Light's retail load. In addition, on November 2012 City Light negotiated a separate contract with WMRE to buy an additional 6 aMW per year from this plant, which started in August 2014.

King County West Point Treatment Plant: In 2010, City Light executed a power purchase agreement with King County for the output of a cogeneration plant at the West Point Wastewater Treatment Facility in Seattle. The County declared commercial operation effective January 2014. The 4.6 MW plant is expected to provide about 2 aMW of electrical energy and associated renewable energy credits (RECs). The contract has specific prices and annual escalation and extends for 20 years after commercial operations begin.

Appendix B: Forecast-Budget Crosswalk

This appendix provides detail on the relationship between the costs in the budget and the financial forecast. The two methods of looking at future costs treat these costs differently because they have two different objectives. Primarily, the budget sets spending authority, while the financial forecast estimates expenses for future compliance with City Light's financial policies. In many instances the budget and the financial forecast expenses are the same. However, there are a number of expense categories where the two have different definitions and or assumed values of expenses. The goal of this appendix is to explain how and why the two methods are different.

The financial forecast was developed as part of the strategic planning process and was finalized in early 2016. City Light's Proposed Budget was not finalized until June of 2016. This crosswalk shows that the differences between the expenses in the budget and financial forecast are either expected based on explicit assumptions or reasonable given the time between when they were developed. Therefore, the revenue requirement is sized appropriately to cover expenses authorized in City Light's 2017-2018 budget.

Summary
Table B.1 provides a high-level comparison of the expenses in the budget and the forecast. While there are several differences, the major drivers of the total forecast-to-budget expense differences are that the forecast:

- Nets out short-term purchased power from revenues;
- Includes a $10M under expenditure assumption in O&M and a 10% under expenditure assumption in CIP; and
- Projects lower environmental cleanup costs than budgeted.

Table B.1
Forecast-Budget Crosswalk Summary

$ Millions	2017 Budget	2018 Budget	2017 Forecast	2018 Forecast	2017 Difference	2018 Difference
Operating Expenses						
Total Non-Power O&M	$362.3	$377.2	$264.8	$280.7	($97.5)	($96.5)
Long-Term Purchased Power	$299.1	$311.1	$283.6	$289.3	($15.5)	($21.8)
Short-Term Purchased Power	$40.4	$40.4	-	-	($40.4)	($40.4)
Taxes	$94.4	$98.8	$101.3	$106.0	$6.9	$7.3
Debt Service	$213.4	$227.3	$206.2	$220.3	($7.1)	($7.0)
Capitalized Expenses						
CIP	$410.2	$385.2	$391.9	$346.2	($18.3)	($39.1)
Deferred O&M	$42.1	$48.1	$49.4	$53.2	$7.3	$5.1
Adjust for CIP Loadings	($80.6)	($77.5)	-	-	$80.6	$77.5
Adjust for AFUDC	($14.4)	($10.8)	-	-	$14.4	$10.8
Total Expenses, less Capital Loadings	**$1,366.9**	**$1,399.8**	**$1,297.2**	**$1,295.6**	**($69.6)**	**($104.2)**

Notes	
Total Non-Power O&M	Most of this difference is due to capitalized overheads. See O&M table B4 for additional detail.
Long-Term Purchased Power	The forecast defers $9.1 million of High Ross costs. See the Long-Term Power Cost table B2 for additional detail.
Short-Term Purchased Power	Net wholesale revenue is forecast as a net revenue so it does not show up in expenses in the summarized forecast. The budget uses a conservative (higher than expected) purchased power value to provide the necessary budget authority in adverse water years.
Taxes	The budget uses paid taxes, while the forecast uses accrued taxes. The forecast also includes bad debt in this category, which is not a budgeted expense. In addition, the budget includes taxes on suburban undergrounding revenue, which is included in deferred O&M in the financial forecast.
Debt Service	The forecast is net of federal interest subsidies while budget uses gross debt service. In addition, the budget includes debt issue costs, while the forecast does not include issue costs in debt service; instead these are netted from bond proceeds.
CIP	See CIP table B6 for details.
Deferred O&M	$9.1 million of High Ross costs are deferred in the forecast. The forecast also includes labor loadings. Other differences reflect cash flow adjustments used in the forecast.
Adjust for Labor Loadings and AFUDC	In the budget, labor loadings are allocated to CIP but are budgeted in O&M. Subtracting them avoids double-counting when aggregating the CIP and O&M budget to compare the total expenses with the forecast. Likewise, AFUDC must be taken out of CIP since all interest expense is included in the debt service category.

Table B.2
Power Contracts Forecast-Budget Crosswalk

$ Millions	2017 Forecast	2018 Forecast	2017 Budget	2018 Budget	2017 Difference	2018 Difference	Notes
Long-Term Purchased Power	**$239.7**	**$244.0**	**$254.7**	**$264.8**	**$14.9**	**($20.8)**	
High Ross	13.1	13.1	22.2	22.2	(9.1)	(9.1)	$9.1 million is deferred in the financial forecast
BPA Costs	175.2	180.6	176.0	185.6	(0.7)	(5.0)	Budget includes higher inflation assumptions. Any BPA cost above or below forecast values will be handled through the BPA passthrough mechanism.
RECs	-	-	3.1	4.4	(3.1)	(4.4)	Forecast includes this in Non-Power O&M
Upstream Storage Benefit	-	-	1.8	1.8	(1.8)	(1.8)	Forecast includes this in Non-Power O&M
Grant County PUD	2.4	2.2	2.4	2.2	-	-	
Green Up RECs	-	-	0.2	0.3	(0.2)	(0.3)	Forecast includes this in Non-Power O&M
SPI SMUD	1.6	-	1.6	-	0.0	-	
GCPHA	6.7	6.9	6.6	6.8	0.1	0.1	
Lucky Peak	7.7	7.9	7.8	8.2	(0.1)	(0.3)	Minor adjustments when Budget was developed
Columbia Ridge	6.3	6.5	6.3	6.5	(0.0)	-	
Stateline	24.6	24.7	24.6	24.7	0.0	-	
King County West Point	2.1	2.1	2.1	2.1	0.0	-	
Wheeling	**43.8**	**45.3**	**44.4**	**46.3**	**(0.6)**	**(1.0)**	
BPA Firm Wheeling	42.6	44.1	42.8	44.7	(0.1)	(0.5)	See BPA note above
AC Intertie Ownership			0.9	0.9	(0.9)	(0.9)	Forecast includes this in Non-Power O&M
Other Wheeling	1.2	1.2	0.7	0.7	0.5	0.5	Forecast includes provision for short-term wheeling. The budget accounts for this in the short-term power budget
TOTAL Power Contract Costs	**283.6**	**289.3**	**299.1**	**311.1**	**(15.5)**	**(21.8)**	

Non-Power O&M

Tables B.3 and B.4 explain the annual changes in Non-power O&M. Table B.3 presents annual changes that were made to the budget through technical adjustments and budget issue papers (BIPs). Note that the 2018 changes shown are incremental to 2017.

Table B.4 lists the adjustments that are made to the O&M budget to get to the O&M forecast for the RRA.

Table B.3
2017 and 2018 Non-Power O&M Budget Changes

$ Millions	**2016 Adopted**	**Inflation & Technical BIPs**	**BIPs**	**2017**	**Inflation & Technical BIPs**	**BIPs**	**2018**
Chief of Staff	$3.5	$0.2	$0.0	$3.7	$0.1	$0.0	$3.8
Power Supply	51.4	1.2	0.6	53.2	0.6	0.9	54.8
Environmental Affairs	26.2	-1.6	-0.1	24.5	0.7	-0.1	25.0
Distribution Services	78.0	1.4	0.2	79.6	3.1	1.4	84.0
Customer Services	31.7	1.5	3.0	36.2	-2.4	4.0	37.8
Human Resources	9.2	0.1	0.0	9.3	0.4	0.0	9.7
Financial Services	43.1	13.9	0.3	57.3	2.5	1.7	61.5
General Expenses	90.4	2.9	0.9	94.2	0.2	1.7	96.1
Compliance	3.7	0.6	0.0	4.2	0.1	0.0	4.4
Total	**$337.2**	**$20.1**	**$4.9**	**$362.3**	**$5.3**	**$9.6**	**$377.2**

Table B.4
2017 and 2018 Non-Power O&M Budget Forecast Crosswalk Detail, $ Millions

Reference			2016 Adopted	2017	2018
A		**Total Non-Power O&M in Budget**	**337.2**	**362.3**	**377.2**
B	add	REC and Intertie Expense in Purchased Power Budget	4.5	4.4	5.8
C	add	PNCA Payments in Purchased Power Budget	1.9	1.9	1.9
D	less	Capital Loadings	83.3	86.9	84.1
E	less	Assumed Budget Under Expenditures	10.0	10.0	10.0
	equals	**Non-Power O&M for Financial Forecast**	**250.3**	**271.6**	**290.8**
		Non Power O&M in 2017-2018 RRA	**255.5**	**264.8**	**280.7**
F		**Difference from Adjusted Budget**	**(5.2)**	**6.8**	**10.1**

Notes	
General	The structure of the O&M categories used in the Financial Forecast is set by FERC based accounting standards, which are used to track financial actuals and calculate financial metrics such as debt service coverage. This is the fundamental reason why the O&M in the budget needs to be adjusted to meet the structure of the financial forecast.
A	This is the total direct non-power O&M in the budget (excludes all deferred O&M, purchased power, taxes, debt service and CIP).
B	REC purchases and Intertie O&M are budgeted in purchased power. However, in the financial forecast they are included in other power costs and transmission, respectively. Therefore, they need to be included in total non-power O&M for the financial forecast.
C	Payments related to the Pacific Northwest Coordination Agreement (PNCA) are budgeted in purchased power but recorded as generation expenses in the financial forecast. These expenses are related to the compensation for the benefits of upstream storage received at City Light's Boundary project.
D	This is the portion of non-power O&M that is forecasted to be overhead expenses associated with the planned levels of CIP and deferred O&M. Overhead expenses include paid time off, fringe benefits, material handling, transportation use, shop handling and A&G. Overhead expenses are capitalized and not included in non-power O&M in the financial forecast. They are implicit in the values of CIP and deferred O&M in the financial forecast. These are only estimates; actual capitalized overheads are determined by cost accounting.
E	Historically, the entire O&M budget has not been fully spent. A $10 million or roughly 3% under-expenditure assumption is used for forecast purposes.
F	These values reflect the differences between the O&M planning values used in the financial forecast and the values from the adjusted O&M Budget. For the years 2017 and 2018 the budget was finalized after the strategic plan was developed and ended up being slightly higher than expected. Key differences include costs required to participate in the Western energy imbalance market (EIM) and higher IT costs (allocated costs from the Department of Technology).

Capital Improvement Program and Deferred O&M

Table B.6 shows how the CIP differs between the budget and the forecast, while table B.7 explains the differences in deferred O&M.

Table B.6
CIP Crosswalk between Budget and Forecast

$ Millions	**2017**	**2018**	**Notes**
CIP Book Totals	**$410.2**	**$385.2**	Budget Values in the 2017-2022 CIP
2016 Lifetime Adjustments	88.8	4.2	Expenditures carried forward from the 2016 budget
Out-Year Lifetime Adjustments	-40.0	0.0	Assumes $40M of each future year's CIP budget will be carried forward to the next year (historical average)
Budget to Expenditure Adjustments	33.5	19.4	Specific adjustments made to selected projects to account for large encumbrance amounts
Remove AFUDC*	-14.4	-10.8	No AFUDC is included in the CIP financial forecast
Spending Adjustments (10%)	-47.8	-39.8	Forecast assumes 90% of spending is realized
Total CIP Cash Flow in 2016 CIP	**$430.3**	**$358.2**	Total cash spending assumed in the 2016 CIP
Total CIP Cash Flow in 2017-2018 Rate Case	**$391.9**	**$346.2**	Total CIP spending assumed in the 2017-2018 Rate Case
Difference	-38.4	-12.1	The difference is mostly due to the large amount of carry forwards from 2016

* AFUDC refers to capitalizing the interest costs that are part of the cost of acquiring certain assets. The financial forecast does not include these costs as part of capital expenses for purposes of developing the revenue requirement. AFUDC is a reduction to accrued interest expense on the income statement.

Table B.7
Deferred O&M Crosswalk between Budget and Forecast

	2017 Budget	2018 Budget	2017 Forecast	2018 Forecast	2017 Difference	2018 Difference
$ Millions						
Deferred O&M						
Programmatic Conservation	$29.6	$35.5	$35.7	$36.4	$6.1	$0.9
Environmental Mitigation and Miscellaneous	12.5	12.6	4.6	7.7	(7.9)	(4.9)
High Ross	0.0	-	9.1	9.1	9.1	9.1
Total	**$42.1**	**$48.1**	**$49.4**	**$53.2**	**$7.3**	**$5.1**
Notes						
Programmatic Conservation	The forecast includes labor loadings and also payment lags for multi-year programs					
Environmental Mitigation and Miscellaneous	The Budget incorporates spending authority of $10.6 million for environmental cleanup, whereas the forecast estimates actual spending amounts of around $2.3 million in 2017 and $6.4 million in 2018. Also, the forecast reflects labor loadings and payment timing lags on relicensing mitigation measures at the Skagit Facilities. In addition the forecast defers around $1 million of taxes associated with suburban undergrounding CIAC.					
High Ross	The Budget does not defer any High Ross Payments.					

Appendix C: Capital Improvement Plan

The City's biennial budget process approves the annual funding levels for CIP. Expenditures for all new and existing projects are reviewed and project details for each capital project are kept in City Light's budget system. Capital projects become part of the City Light CIP proposal after an identification, selection and prioritization process in which project justification, costs and benefits are closely examined. City Light has implemented a more rigorous utility-wide prioritization process over the last several years requiring that new initiatives and existing projects with major changes in scope or budget provide a business case and economic analysis that justifies funding for the project. The economic analysis includes a discussion of all benefits and costs, including customer service, legal and technical considerations, environmental and risk impacts. Every two years, the Mayor and the City Council, as part of the City's biennial budget process, review proposed capital expenditures for the budget period, approving expenditures for the first year and endorsing expenditures for the second year.

Table C.1 shows 2017-2022 CIP spending from the Proposed 2016 CIP Plan. The project amounts included in the following paragraphs reflect the total 2017-2022 CIP spending and do not represent total life-time project costs. Appendix B shows the difference between The CIP assumptions in the Strategic Plan and the Proposed 2016 CIP Plan, discussed below.

Central Utility. These expenses are related to General Plant and include investments in non-electrical system assets including buildings and facilities, such as the North and South Service Centers, and investments in office-related computer equipment, information and communications systems, furniture, and mobile equipment. Over the six-year planning period, the largest projects are expected to be: the Service Center Development Project ($99.9 million), Replacement of Equipment Fleet ($46.2 million), and Miscellaneous Building Improvements ($17.2 million).

Distribution. Distribution plant includes poles, wires and cables, transformers, manholes, vaults, ducts, and other electrical equipment and infrastructure needed to deliver power from the substation to the customer connection at home or business in both network and non-network areas. Over the six-year planning period, the largest projects are expected to be: Replacement of Overhead Equipment ($135.2 million), Replacement of Underground Equipment ($72.0 million) and Service Connection work for Medium Customers ($72.5 million).

External Projects. These projects include work related to relocating infrastructure for transportation projects, investments in streetlight assets and various undergrounding work. Over the six-year planning period, the largest projects are expected to be: the Alaskan Way Viaduct and Seawall Replacement ($90.5 million), the Enterprise Software Solution Replacement Strategy ($40.1 million), and the Streetlight LED Conversion Program ($37.5 million).

Power Supply. Power Supply includes generation facilities used to produce electricity. Typical assets would be reservoirs, dams, waterways, waterwheels, turbines, generators and accessory electrical equipment. Over the six-year planning period, the largest projects are expected to be: License Mitigation at the Boundary facility ($115.0 million) and Relicensing ($52.9 million) and Minor Improvement Programs ($38.2 million) at the Skagit facility.

Transmission. Transmission plant includes poles, towers and conductors used to carry electricity from generation facilities to substations. Over the six-year planning period, the largest projects are expected to be: Transmission lines for the Denny Substation ($62.5 million), Transmission Reliability ($18.1 million), and Transmission Line Inductor Installations ($12.9 million).

Table C.1
Total CIP Expenditures

$ Millions	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Central Utility Projects	$50.3	$35.6	$23.8	$26.6	$89.0	$70.7	$296.0
Distribution	257.1	191.3	179.2	171.0	193.0	203.4	1,195.0
External Projects	61.4	59.7	50.9	41.0	41.9	42.3	297.1
Power Supply	90.3	95.6	76.2	73.2	100.0	97.1	532.4
Transmission	19.0	15.9	6.9	9.7	45.7	4.3	101.5
Subtotal	**$478.1**	**$398.0**	**$336.8**	**$321.5**	**$469.7**	**$417.9**	**$2,422.0**
10% Under Expenditure	47.8	39.8	33.7	32.1	47.0	41.8	242.2
Total CIP Cash Expenditures	430.3	358.2	303.1	289.3	422.7	376.1	2,179.8

Table C.2
Central Utility Projects CIP Detail

$ Millions	2017	2018	2019	2020	2021	2022	Total
Central Utility Projects	**50.3**	**35.6**	**23.8**	**26.6**	**89.0**	**70.7**	**296.0**
E1: Customer and Billing	**5.2**	**-**	**-**	**-**	**-**	**-**	**5.2**
9937: Customer Information System	5.2	-	-	-	-	-	5.2
E2: Finance and IT Systems	**17.9**	**14.3**	**5.4**	**3.8**	**5.3**	**3.4**	**50.2**
9915: Information Technology Infrastructure	0.5	0.5	0.5	0.5	0.5	0.5	3.0
9933: Enterprise Performance Management	1.5	-	-	-	-	-	1.5
9960: IT Security Upgrades	0.5	1.1	1.1	1.2	0.5	0.6	5.0
9962: Enterprise Document Management System	2.0	2.8	1.7	1.4	1.1	0.7	9.8
9967: Outage Management System Phase II Implementation	1.3	2.1	-	-	-	-	3.4
9970: PeopleSoft Reimplementation - City Light	8.8	2.3	-	-	-	-	11.1
9973: Project Management System Impl	-	-	-	-	2.0	1.0	3.0
9974: Asset Condition Assessment and Test Tracking System	-	-	1.9	0.7	1.0	0.4	3.9
9975: Data Warehouse Implementation	0.2	0.2	0.2	0.2	0.2	0.2	0.9
9976: Western Energy Imbalance Market	3.1	5.3	-	-	-	-	8.5
E3: Fleets and Facilities	**27.2**	**21.2**	**18.3**	**22.7**	**83.7**	**67.3**	**240.6**
8389: Special Work Equipment - Shops	0.3	0.3	0.3	0.3	0.3	0.3	1.9
9006: Safety Modifications	1.3	1.3	1.4	1.4	1.4	1.4	8.1
9007: Miscellaneous Building Improvements	1.5	2.2	2.3	3.7	3.8	3.8	17.2
9072: Building Envelope Upgrades	1.6	1.6	1.2	1.3	1.3	1.3	8.3
9101: Equipment Fleet Replacement	6.9	7.7	7.2	7.2	7.2	10.1	46.2
9103: Office Furniture and Equipment Purchase	0.6	0.7	1.1	1.1	1.2	1.2	5.9
9107: North and South Service Center Improvements	0.3	0.3	0.8	3.9	5.3	5.4	16.0
9134: Seismic Mitigation	0.1	0.1	0.1	0.6	0.6	0.6	2.1
9151: Facilities Regulatory Compliance	0.3	0.3	0.3	0.4	0.4	0.4	2.1
9152: Environmental Safeguarding and Remediation of Facilities	0.1	0.1	0.1	0.1	0.1	0.1	0.4
9156: Facilities Infrastructure Improvements	0.4	0.4	0.1	0.1	0.1	0.1	1.1
9159: Workplace and Process Improvement	2.2	1.3	2.0	1.9	2.3	2.3	12.0
9161: Substation Comprehensive Improvements	0.2	0.3	0.2	0.3	0.3	-	1.3
9230: Technical Training Center Development	7.9	1.5	0.6	-	-	-	10.0
9232: Service Center Development Project	-	-	-	-	59.6	40.3	99.9
9233: Georgetown Steamplant Access Road	0.6	0.7	-	-	-	-	1.3
9236: Stormwater Compliance	0.5	0.5	0.5	0.5	-	-	2.0
9237: Electric Vehicle Infrastructure	1.6	1.1	-	-	-	-	2.7
9238: Solar Microgrid for Resilience	0.0	0.0	-	-	-	-	0.0
9320: Energy Conservation	0.3	0.3	0.1	0.1	0.1	0.1	1.1
9972: Call Center Improvements - City Light	0.5	0.5	-	-	-	-	1.0

Table C.3
Distribution Projects CIP Detail

$ Millions	2017	2018	2019	2020	2021	2022	Total
Distribution	**257.1**	**191.3**	**179.2**	**171.0**	**193.0**	**203.4**	**1,195.0**
C1: Substations	**80.3**	**33.2**	**25.6**	**25.4**	**27.3**	**27.6**	**219.5**
7121: Replace Breakers BPA Covington and MV Substations	0.0	0.0	0.0	0.0	0.0	0.0	0.1
7750: Substation Plant Improvements	0.8	0.9	0.9	0.9	1.2	1.5	6.3
7751: Substation Capacity Additions	1.7	2.0	2.1	2.4	2.0	2.1	12.4
7752: Substation Equipment Improvements	4.7	5.9	6.7	6.7	6.5	6.1	36.6
7753: Relaying Improvements	3.6	4.5	5.5	4.5	4.8	4.9	27.8
7755: Substations Demand Driven Improv.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7756: Interbay Substation – Development	-	-	0.1	0.1	0.4	0.5	1.0
7757: Denny Substation Development	56.4	9.5	-	-	-	-	65.9
7776: Substation Transformer Replacements	2.0	2.5	2.6	3.6	4.9	4.7	20.4
7779: Substation Breaker Replacements and Reliability Additions	5.7	4.8	5.6	5.1	6.0	5.9	33.0
7783: Substations Oil Containment	0.3	0.3	0.3	0.3	0.2	0.6	2.2
8424: Substation Automation	1.2	1.4	1.7	1.7	1.3	1.3	8.6
9235: Denny Substation Tenant Improvements	3.8	1.4	0.0	-	-	-	5.2
C2: Network	**46.1**	**22.9**	**22.0**	**31.0**	**42.3**	**39.0**	**203.3**
8129: Network Hazeltine Upgrade	0.5	0.5	0.6	0.8	0.7	0.7	3.9
8130: Network Maintenance Hole and Vault Rebuild	3.1	3.5	3.5	3.5	3.6	2.6	19.9
8201: Union Street Substation Networks	2.3	2.6	2.6	2.7	2.9	3.0	16.1
8202: Massachusetts Street Substation - Networks	3.7	3.9	4.0	4.4	3.1	4.7	23.8
8203: Broad Street Substation - Network	8.3	3.2	3.7	4.6	9.0	3.0	31.8
8301: First Hill - Network	2.4	2.6	2.7	2.7	2.0	5.1	17.5
8404: Denny Substation - Network	25.3	6.2	3.6	10.9	12.4	11.2	69.8
8407: First Hill - Network Load Transfer	-	-	0.9	0.9	7.9	8.1	17.8
8464: University Substation - Network	0.4	0.4	0.4	0.5	0.5	0.5	2.6
C3: Radial	**55.0**	**54.6**	**63.3**	**62.8**	**67.4**	**74.2**	**377.3**
8322: Dallas Ave. 26 kV Crossing	0.0	0.1	0.0	0.0	0.0	-	0.2
8351: Overhead Equipment Replacements	17.4	18.2	25.4	25.7	23.5	25.2	135.2
8353: Underground Equipment Replacements	11.0	10.3	10.4	8.6	14.8	16.8	72.0
8355: Overhead Customer Driven Capacity Additions	3.5	4.3	5.0	5.6	4.0	6.0	28.5
8356: Overhead System Capacity Additions	2.5	2.6	2.6	2.6	3.4	3.4	17.0
8358: Overhead 26kV Conversion	1.6	1.7	1.7	1.8	1.8	1.4	10.0
8360: Underground Customer Driven Capacity Additions	2.0	2.2	2.4	2.3	2.3	3.7	14.8
8361: Underground System Capacity Additions	2.7	2.9	3.0	2.4	4.3	4.3	19.6
8362: Underground 26kV Conversion	1.5	2.0	2.5	2.5	2.7	4.1	15.4
8373: Laurelhurst - Underground Rebuild	0.1	-	-	-	-	-	0.1
8425: Distribution Automation	3.5	2.2	2.8	2.9	2.9	1.4	15.6

Table C.3
Distribution CIP Detail (continued)

$ Millions	2017	2018	2019	2020	2021	2022	Total
8429: Mobile Workforce Implementation	2.7	1.6	1.2	1.3	-	-	6.8
8452: Pole Attachment Requests Preparation Work	3.3	3.6	3.6	4.0	4.5	4.6	23.6
8465: Broadband - City Light	2.5	2.7	2.8	3.1	3.2	3.2	17.5
9950: Automated Utility Design Implementation	0.6	0.1	-	-	-	-	0.7
C4: Service Connections	**64.3**	**67.0**	**52.6**	**40.2**	**43.5**	**53.5**	**321.0**
8054: Meter Additions	2.1	2.3	2.6	2.7	2.8	3.0	15.6
8350: Overhead Outage Replacements	0.3	0.3	0.5	1.0	1.0	1.1	4.1
8352: Underground Outage Replacements	1.1	1.2	1.5	2.0	2.0	1.7	9.4
8363: Network Additions and Services: Broad Street Substation	6.0	6.8	6.8	6.9	7.1	7.0	40.6
8364: Network Additions and Svcs: First Hill, Mass, Union & University	3.7	2.9	3.0	3.0	3.5	3.6	19.8
8365: Large Overhead and Underground Services	2.7	3.0	4.2	3.2	5.0	6.4	24.6
8366: Medium Overhead and Underground Services	12.8	14.3	11.3	11.1	8.8	14.3	72.5
8367: Small Overhead and Underground Services	5.7	6.3	5.5	5.4	5.3	6.7	34.9
8379: Normal Emergency	0.5	0.6	1.3	1.3	2.5	2.5	8.8
8380: Major Emergency	0.2	0.3	0.3	0.3	1.4	1.5	3.9
8405: Network Additions and Services - Denny	2.1	2.7	2.7	2.5	3.1	4.9	18.0
8426: Advanced Metering Infrastructure	27.1	26.0	12.2	-	-	-	65.2
8483: Vista Switch Automation	-	0.4	0.8	0.8	0.8	0.8	3.6
C5: Distribution Other	**11.3**	**13.7**	**15.7**	**11.5**	**12.5**	**9.2**	**73.9**
8484: Battery Storage Pilot	0.5	0.5	0.5	0.5	0.5	0.5	3.0
8485: Special Work Equipment - Tech Metering	0.2	0.2	0.2	0.2	0.2	0.2	1.3
9009: Communications Improvements	1.0	0.9	0.9	0.9	1.0	0.8	5.5
9102: Special Work Equipment - Other Plant	1.0	1.1	1.1	1.2	1.2	1.2	6.8
9108: Transmission & Generation Radio Systems	1.1	1.3	0.7	0.9	1.0	1.0	6.1
9202: Security Improvements	2.8	2.2	2.2	2.2	2.3	2.3	14.0
9307: Distribution Area Communications Networks	1.0	2.7	2.5	2.9	2.8	2.0	13.8
9956: Energy Management System	0.4	-	-	-	-	-	0.4
9957: Enterprise Geographic Information System	3.0	4.7	2.5	-	-	-	10.3
9965: Tool Room Automation	0.4	-	-	-	-	-	0.4
9966: Distribution Management System	-	-	5.0	2.7	0.2	-	7.9
9968: Asset Investment and Optimization	-	-	-	-	3.4	1.1	4.5

Table C.4
External Projects CIP Detail

$ Millions	2017	2018	2019	2020	2021	2022	Total
External Projects	**61.4**	**59.7**	**50.9**	**41.0**	**41.9**	**42.3**	**297.1**
D1: Local Jurisdictions	**15.8**	**16.6**	**19.0**	**26.2**	**25.1**	**27.3**	**130.1**
8377: Transportation Streetlights	4.1	4.2	4.0	4.0	4.1	7.1	27.5
8378: Streetlights: Arterial, Residential and Floodlights	3.2	3.5	3.8	4.3	4.9	5.1	24.8
8403: Citywide Undergrounding Initiative - City Light	0.0	0.0	0.0	0.0	0.0	0.0	0.1
8441: Streetlight LED Conversion Program	5.3	5.4	6.1	7.0	6.7	6.9	37.5
8460: Streetlight Infrastructure Replacement	2.9	3.2	3.3	4.0	4.4	4.2	21.8
8480: Fauntleroy Undergroundings	-	-	1.5	2.0	-	-	3.5
8481: Seattle Waterfront Streetlight Installation	0.3	0.3	0.4	5.0	5.0	4.0	15.0
D2: Transportation Relocations	**45.3**	**41.5**	**21.8**	**7.8**	**6.3**	**3.9**	**126.6**
8307: Alaska Way Viaduct and Seawall Replacement - Utility Relocs	36.3	33.2	17.4	2.3	1.3	-	90.5
8369: Transportation Driven Relocations	2.0	2.3	2.6	3.8	3.9	3.9	18.5
8427: Sound Transit Northlink - City Light	1.3	-	-	-	-	-	1.3
8435: State Route 520 Bridge Relocations	0.6	0.4	0.2	0.0	0.0	-	1.3
8442: First Hill Connector Streetcar	0.9	-	-	-	-	-	0.9
8450: Sound Transit Light Rail East Link - City Light	0.9	0.0	-	-	-	-	0.9
8470: Center City Connector Streetcar - City Light	1.9	4.0	-	-	-	-	5.9
8471: Sound Transit Lynnwood - City Light	1.4	1.5	1.6	1.6	1.1	-	7.2
8475: Sound Transit - City Light System Upgrades	0.1	-	-	-	-	-	0.1
D3: Customer Other	**0.3**	**1.6**	**10.0**	**7.0**	**10.5**	**11.0**	**40.5**
8383: Neighborhood Voluntary Undergrounding Program	0.0	0.0	0.0	0.0	0.0	0.0	0.1
8430: Creston-Nelson to Intergate East Feeder Installation	0.3	0.0	-	-	-	-	0.3
9969: Enterprise Software Solution Replacement Strategy	-	1.6	10.0	7.0	10.5	11.0	40.1

Table C.5
Power Supply CIP Detail

$ Millions	2017	2018	2019	2020	2021	2022	Total
Power Supply	**90.3**	**95.6**	**76.2**	**73.2**	**100.0**	**97.1**	**532.4**
A1: Boundary	**39.0**	**64.6**	**49.6**	**37.0**	**47.5**	**36.2**	**273.9**
6343: Boundary Dam - Instrumentation Upgrade and Integration	1.0	0.5	-	-	-	-	1.5
6351: Boundary Powerhouse - Unit 51 Generator Rebuild	3.0	10.8	4.4	1.6	-	-	19.9
6353: Boundary Powerhouse - Unit 54 Generator Rebuild	-	7.3	5.3	5.0	1.7	-	19.2
6401: Boundary Facility - Minor Improvements Program	1.4	2.0	4.3	10.7	7.1	12.2	37.7
6485: Boundary Powerhouse - Transformer Bank Rockfall Mitigation	-	-	0.2	0.1	3.2	14.8	18.4
6493: Boundary Switchyard - Generator Step-up Transformers	7.6	6.6	6.4	6.1	8.0	-	34.6
6535: Boundary Powerhouse - Unit 52 Generator Rebuild	-	-	11.8	1.0	5.1	1.6	19.5
6565: Landis and Gyr RTU Modernization Boundary, CF, Skagit	-	-	0.5	0.7	0.6	-	1.8
6566: Boundary - DC Battery System & Charge Modernization	0.1	-	-	-	-	-	0.1
6601: Boundary Entrance Improvements	2.0	-	-	-	-	-	2.0
6602: Boundary U55 Exciter replacement	0.0	-	-	-	-	-	0.0
6603: Boundary U56 Exciter Replacement	0.5	0.0	-	-	-	-	0.6
6615: Boundary - Access Road Stability Improvements	0.5	1.1	-	-	-	-	1.6
6620: Boundary Crane Improvements	0.9	1.1	-	-	-	-	2.0
6987: Boundary - Licensing Mitigation	21.9	35.2	16.7	11.8	21.8	7.5	115.0
A2: Skagit	**44.3**	**25.3**	**18.2**	**28.3**	**43.6**	**55.2**	**215.0**
6232: Skagit - Sewer System Rehabilitation	0.6	0.5	2.8	0.2	-	-	4.1
6326: Gorge Powerhouse - Fire Protection Improvements	0.1	0.0	0.2	0.3	0.1	0.1	0.9
6373: Ross Dam - AC/DC Distribution System Upgrade	1.6	0.4	-	3.7	-	-	5.7
6376: Ross Powerhouse - Programmable Language Controller Upgrade	0.4	0.1	-	-	-	-	0.5
6405: Skagit Facility - Minor Improvements Program	2.1	2.6	1.2	4.6	13.7	14.1	38.2
6415: Skagit Powerhouses - Install Protection Relays	1.4	1.8	0.5	1.9	1.5	1.0	8.1
6422: Diablo Powerhouse - Rebuild Generator Unit 31	12.4	1.3	-	-	-	-	13.7
6423: Diablo Powerhouse - Rebuild Generator Unit 32	6.3	10.0	0.2	-	-	-	16.6

Table C.5
Power Supply CIP Detail (continued)

$ Millions	2017	2018	2019	2020	2021	2022	Total
6452: Ross Dam - New Access Road from SR20 to Dam	-	-	-	0.4	12.8	6.9	20.2
6457: Diablo Facility - Incline Lift Rehabilitation	-	-	-	0.0	0.1	0.6	0.7
6479: Newhalem - Generator 20/Support Facility Rebuild	0.1	0.3	-	-	-	-	0.4
6483: Diablo Facility - Lines Protection Upgrades	0.0	0.1	1.7	0.1	-	-	1.9
6514: Skagit - Babcock Creek Crossing	0.0	-	-	-	-	-	0.0
6515: Skagit - Facilities Energy Conservation Program	0.0	1.0	-	-	-	-	1.1
6516: Ross Rock Slide Area Improvements	0.0	-	-	-	-	-	0.0
6520: Skagit Facilities Plan	2.0	2.6	-	-	-	-	4.7
6532: Diablo Load Interrupters Replacement	2.3	0.6	-	-	-	-	2.9
6540: Skagit Boat Facility Improvements	0.6	0.4	-	-	-	-	1.0
6541: Ross Powerhouse - Replace Transformer Banks 42 and 44	7.9	0.1	-	-	-	-	7.9
6562: Ross Governors	3.2	0.6	-	-	-	-	3.7
6564: Ross Exciters 41 - 44	-	0.4	3.2	0.2	0.7	-	4.6
6577: Ross - Powerhouse Rockfall Mitigation	0.1	0.4	0.0	4.4	-	-	4.9
6580: Ross - 480V AC Station Service Switchgear Replacement	-	-	0.1	5.5	-	-	5.6
6581: Gorge - 240V AC Station Service Switchgear Replacement	1.8	-	-	-	-	-	1.8
6582: Ross - R1 and R2 Relay and Instrumentation Upgrade	0.1	0.1	0.4	0.1	-	-	0.7
6583: Skagit - DC Battery System & Charge Modernization	0.3	-	-	-	-	-	0.3
6589: Diablo - Replace Bank Transformers	-	-	-	0.1	0.9	7.5	8.5
6610: Diablo Dam - Spill Gate Trunnion Upgrades	0.4	0.5	0.5	0.5	0.5	0.2	2.6
6986: Skagit Relicensing	0.5	1.3	7.2	6.1	13.3	24.6	52.9
6991: Skagit Licensing Mitigation	0.1	0.1	0.1	0.1	0.1	0.1	0.7
A3: Cedar Falls - Tolt	**3.0**	**1.7**	**3.7**	**4.2**	**6.1**	**3.0**	**21.7**
6324: Cedar Falls Powerhouse - Valvehouse Rehabilitation	-	-	-	0.7	3.0	-	3.7
6358: Cedar Falls Powerhouse - Penstock Stabilization	-	-	0.3	0.6	0.2	-	1.1
6406: Cedar Falls/South Fork Tolt - Minor Improvements Program	2.3	1.3	1.2	2.3	2.9	3.0	12.9

Table C.5
Power Supply CIP Detail (continued)

$ Millions	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
6450: Cedar Falls Powerhouse - Unit 5/6 Generator Protective Relay	0.5	0.1	-	-	-	-	0.6
6531: Cedar Falls - New Generator 5/6 Exciters	0.2	-	-	-	-	-	0.2
6570: South Fork Tolt - DC Battery System & Charge Modernization	0.0	-	-	-	-	-	0.0
6572: Cedar Falls - DC Battery System and Charge Modernization	0.0	-	-	-	-	-	0.0
6573: Cedar Falls - Bank 6 Replacement	-	0.3	2.1	0.7	-	-	3.2
A4: Power Supply Other	**4.0**	**4.0**	**4.7**	**3.8**	**2.7**	**2.7**	**21.8**
6102: Special Work Equipment - Generation Plant	0.9	1.0	1.4	1.5	1.0	1.1	6.8
6385: Power Production - Network Controls	0.5	0.8	0.9	-	-	-	2.2
6470: Generation Federal Reliability Standards Improvements	0.0	0.0	0.0	0.0	-	-	0.0
6530: Hydro Project Spill Containment	0.7	0.2	0.7	0.7	-	-	2.3
6600: SMT AutoLab	0.2	0.5	-	-	-	-	0.7
6625: Cedar Falls Rehabilitation	0.2	0.3	0.3	0.3	0.3	0.3	1.5
6626: Dam Safety Part 12 Improvements	0.4	0.3	0.3	0.2	0.2	0.2	1.5
6990: Endangered Species Act Mitigation	1.0	1.1	1.1	1.2	1.2	1.2	6.9

Table C.6
Transmission CIP Detail

$ Millions	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Transmission	**19.0**	**15.9**	**6.9**	**9.7**	**45.7**	**4.3**	**101.5**
B1: Transmission	**19.0**	**15.9**	**6.9**	**9.7**	**45.7**	**4.3**	**101.5**
7011: Transmission Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.1
7104: Transmission Reliability	2.6	2.9	3.0	3.1	2.7	3.7	18.1
7105: Transmission Inter-Agency	0.5	0.6	0.6	0.6	0.6	0.6	3.6
7125: Denny Substation Transmission Lines	7.3	4.7	2.2	6.0	42.4	-	62.5
8461: Transmission Line Inductor Installation	5.8	6.1	1.0	-	-	-	12.9
8462: Transmission Line Reconductoring	2.8	1.5	-	-	-	-	4.3